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Power System Operation and Control

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22.1 Implementation of Distribution Automation

The implementation of “distribution automation” within the continental U.S. is as diverse and numerous as the utilities themselves. Particular strategies of implementation utilized by various utilities have depended heavily on environmental variables such as size of the utility, urbanization, and available communication paths. The current level of interest in distribution automation is the result of:

- The August 14, 2003 northeast blackout, which focused attention on infrastructure deficiencies and increased industry attention on sensor technology and digital control systems.
- Recent initiatives such as the DOE’s GridWise program and EPRI’s IntelliGrid program that have funded distribution research and development projects.
- The availability of low-cost, high-performance general purpose microprocessors, embedded processors, and digital signal processors, which have extended technology choices by blurring the lines between traditional RTU, PLC, meter, and relay technologies, specifically capabilities that include meter accuracy measurements and calculations with power quality information including harmonic content.

- Increased performance in host servers for the same or lower cost, lower cost of memory, and in particular the movement to Windows and Linux architectures.
- The threat of deregulation and competition as a catalyst to automate.
- Strategic benefits to be derived (e.g., potential of reduced labor costs, better planning from better information, optimizing of capital expenditures, reduced outage time, increased customer satisfaction).

While not meant to be all-inclusive, this section on distribution automation attempts to provide some dimension to the various alternatives available to the utility engineer. The focus will be on providing insight on the elements of automation that should be included in a scalable and extensible system. The approach will be to describe the elements of a “typical” distribution automation system in a simple manner, offering practical observations as required.

The supervisory control and data acquisition (SCADA) vendors are now delivering systems on the Windows platform running on PC workstations. The PC-based systems provide opportunities to distribute the SCADA technology throughout the electric distribution network.

22.2 Distribution SCADA History

SCADA is the foundation for the distribution automation system. The ability to remotely monitor and control electric power system facilities found its first application within the power generation and transmission sectors of the electric utility industry. The ability to significantly influence the utility bottom line through the effective dispatch of generation and the marketing of excess generating capacity provided economic incentive. The interconnection of large power grids in the Midwestern and the Southern U.S. (1962) created the largest synchronized system in the world. The blackout of 1965 prompted the U.S. Federal Power Commission to recommend closer coordination between regional coordination groups (Electric Power Reliability Act of 1967), and gave impetus to the subsequent formation of the National Electric Reliability Council (1970). From that time (1970) forward, the priority of the electric utility has been to engineer and build a highly reliable and secure transmission infrastructure. The importance and urgency of closer coordination was re-emphasized with the northeast blackout of 2003. Transmission SCADA became the base for the large energy management systems that were required to manage the transmission grid.

Distribution SCADA was not given equal consideration during this period. For electric utilities, justification for automating the distribution system, while being highly desirable, was not readily attainable based on a high cost/benefit ratio due to the size of the distribution infrastructure and cost of communication circuits. Still there were tactical applications deployed on parts of distribution systems that were enough to keep the dream alive.

The first real deployments of distribution SCADA systems began in the late 1980s and early 1990s when SCADA vendors delivered reasonably priced “small” SCADA systems on low-cost hardware architectures to the small co-ops and municipality utilities. As the market expanded, SCADA vendors who had been providing transmission SCADA began to take notice of the distribution market. These vendors initially provided host architectures based on VAX/VMS and later on Alpha/OpenVMS platforms and on UNIX platforms. These systems were required for the large distribution utility (100,000–250,000 point ranges). These systems often resided on company-owned LANs with communication front-end (CFE) processors and user interface (UI) attached either locally on the same LAN or across a WAN.

In the mid-1980s, EPRI published definitions for distribution automation and associated elements. The industry generally associates distribution automation with the installation of automated distribution line devices such as switches, reclosers, sectionalizers, etc. The author’s definition of distribution automation encompasses the automation of the distribution substations and the distribution line

devices. The automated distribution substations and the automated distribution line devices are then operated as a system to facilitate the operation of the electric distribution system.

22.2.1 SCADA System Elements

At a high level, the elements of a distribution automation system can be divided into three main areas:

- SCADA application and servers
- DMS applications and servers
- Trouble management applications and servers

22.2.2 Distribution SCADA

As was stated in the introduction, the SCADA system is the heart of distribution management system (DMS) architecture. A SCADA system should have all of the infrastructure elements to support the multifaceted nature of distribution automation and the higher level applications of a DMS. A distribution SCADA system's primary function is in support of distribution operations telemetry, alarming, event recording, and remote control of field equipment. Historically, SCADA systems have been notorious for their lack of support for the import, and more importantly, the export of power system data values. A modern SCADA system should support the engineering budgeting and planning functions by providing access to power system data without requiring possession of an operational workstation. The main elements of a SCADA system are:

- Host equipment
- Communication infrastructure (network and serial communications)
- Field devices (in sufficient quantity to support operations and telemetry requirements of a DMS platform)

22.2.3 Host Equipment

The authors feel that the essential elements of a distribution SCADA host are:

- Host servers (redundant servers with backup/failover capability)
- Communication front-end nodes (network based)
- Full graphics user interfaces
- Relational database server (for archival of historical power system values) and data server/Web server (for access to near real-time values and events)

The elements and components of the typical distribution automation system are illustrated in Fig. 22.1.

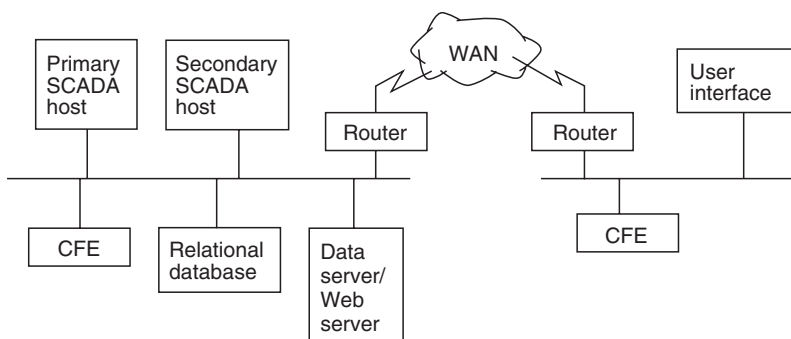


FIGURE 22.1 DA system architecture.

22.2.4 Host Computer System

22.2.4.1 SCADA Servers

As SCADA has proven its value in operation during inclement weather conditions, service restoration, and daily operations, the dependency on SCADA has created a requirement for highly available and high-performance systems. High-performance servers with abundant physical memory, RAID hard disk systems, and LAN connection are typical of today's SCADA high-performance servers. Redundant server hardware operating in a "live" backup/failover mode is required to meet the high availability criteria. In meeting the high availability criteria, electric utilities may also include a remote SCADA host configuration for disaster recovery.

22.2.5 Communication Front-End Processors

Most utilities will utilize more than one communication medium with the particular choice based on system requirements and other variables (e.g., radio coverage). However the preponderance of host to field device communications still depends heavily on serial communications. That is to say no matter what the communication medium used, the electrical interface to the SCADA system (CFE) is still most often a serial interface, not a network interface. The host/RTU interface requirement is filled by the CFE. The CFE can come in several forms based on bus architecture (older CFE technologies were most often based on VME or PCI bus systems with custom serial controllers). Currently CFE architectures are moving to Intel/Windows architectures with the serial controller function performed by the main processor instead of having the serial controllers located on the serial card. Location of the CFE in relation to the SCADA server can vary based on requirement. In some configurations the CFE is located on the LAN with the SCADA server. In other cases, existing communications hubs may dictate that the CFE resides at the communication hub. The incorporation of the WAN into the architecture requires a more robust CFE application to compensate for intermittent interruptions of network connectivity (relatively speaking—comparing WAN to LAN communication reliability).

The advent of new architectures for CFEs will offer new capabilities and opportunities for sharing data within the utility. The ability to serve data through a nonproprietary protocol such as ICCP offers the possibility for rethinking SCADA architectures within large utilities that may have more than one SCADA system or more than one audience for SCADA information.

In general the CFE will include three functional devices: a network/CPU board, serial cards, and possibly a time code receiver. Functionality should include the ability to download configuration and scan tables. The CFE should also support the ability to dead band values (i.e., report only those analog values that have changed by a user-defined amount). Even when exception scanning/reporting is used, the CFE, network and SCADA servers should be capable of supporting worst-case conditions (i.e., all points changing outside of the dead band limits), which typically occur during severe system disturbances. Deterministic communications with known data solicitation rates facilitate the sizing of the SCADA database and the performance of the SCADA system during wide-area storm events. Deterministic serial communications with the RTU are required for secure predictable data acquisition and supervisory control.

22.2.6 Full Graphics User Interface

The current distribution SCADA UI is a full graphics (FG) user interface. While character graphics consoles are still in use by some utilities today, SCADA vendors have aggressively moved their platforms to an FGUI. Initially the SCADA vendors implemented their FGUI on low-cost NT and XP workstations using third-party applications to emulate the X11 window system. Today the UI is being more natively integrated into the Windows architecture or as "browser"-like application. Full graphic displays provide the ability to display power system data along with the electric distribution facilities in a geographical (or semigeographical) perspective. The advantage of using a full graphics interface becomes evident (particularly for distribution utilities) as SCADA is deployed beyond the substation fence where feeder diagrams become critical to distribution operations.

22.2.7 Relational Databases, Data Servers, and Web Servers

The traditional SCADA systems were poor providers of data to anyone not connected to the SCADA system by an operational console. This occurred due to the proprietary nature of the performance (in memory) database and its design optimization for putting scanned data in and pushing display values out. Power system quantities such as bank and feeder loading (MW, MWH, MQH, and ampere loading) and bus volts provide valuable information to the distribution planning engineer. The maintenance engineer frequently uses the externalized SCADA data to identify trends and causality information to provide more effective and efficient equipment maintenance. The availability of event (log) data is important in postmortem analysis. The use of relational databases, data servers, and Web servers by the corporate and engineering functions provides access to power system information and data while isolating the SCADA server from nonoperations personnel.

22.2.8 Host to Field Communications

There are many communication mediums available to distribution SCADA for host/remote communications today. Some SCADA implementations utilize a network protocol over fiber to connect the SCADA hosts to substation automation systems; typically this is more often found in a small co-op or PUD who may have a relatively small substation count. Communication technologies such as frame-relay, multiple address system (MAS) radio, 900 MHz unlicensed, and even satellite find common usage today. Additionally there are new technologies emerging that may enter the mix of host/RTU communications (e.g., WiFi, WiMAX, and even broadband over power line [BPL] are possibilities at least for data acquisition). The authors do not recommend supervisory control over BPL.

Radio technologies offer good communications value. One such technology is the MAS radio. The MAS operates in the 900 MHz range and is omni-directional, providing radio coverage in an area with radius up to 20–25 miles depending on terrain. A single MAS master radio can communicate with many remote sites. The 900 MHz remote radio depends on a line-of-sight path to the MAS master radio. Protocol and bandwidth limit the number of remote terminal units that can be communicated with by a master radio. The protocol limit is simply the address range supported by the protocol. Bandwidth limitations can be offset by the use of efficient protocols, or slowing down the scan rate to include more remote units. Spread-spectrum and point-to-point radio (in combination with MAS) offer an opportunity to address specific communication problems, e.g., terrain changes or buildings within the MAS radio line-of-sight. At the present time MAS radio is preferred (authors' opinion) to packet radio (another new radio technology); MAS radio communications tend to be more deterministic providing for smaller timeout values on communication no-responses and controls.

22.3 Field Devices

Distribution automation (DA) field devices are multifeatured installations meeting a broad range of control, operations, planning, and system performance issues for the utility personnel. Each device provides specific functionality, supports system operations, includes fault detection, captures planning data, and records power quality information. These devices are found in the distribution substation and at selected locations along the distribution line. The multifeatured capability of the DA device increases its ability to be integrated into the electric distribution system. The functionality and operations capabilities complement each other with regard to the control and operation of the electric distribution system. The fault detection feature is the “eyes and ears” for the operating personnel. The fault detection capability becomes increasingly more useful with the penetration of DA devices on the distribution line.

The real-time data collected by the SCADA system are provided to the planning engineers for inclusion in the radial distribution line studies. As the distribution system continues to grow, the utility makes annual investments to improve the electric distribution system to maintain adequate facilities to meet the

increasing load requirements. The use of the real-time data permits the planning engineers to optimize the annual capital expenditures required to meet the growing needs of the electric distribution system.

The power quality information includes capturing harmonic content to the 15th harmonic and recording percent total harmonic distortion (%THD). This information is used to monitor the performance of the distribution electric system.

22.3.1 Modern RTU

Today's modern RTU is modular in construction with advanced capabilities to support functions that heretofore were not included in the RTU design. The modular design supports installation configurations ranging from the small point count required for the distribution line pole-mounted units to the very large point count required for large bulk-power substations and power plant switchyard installations. The modern RTU modules include analog units with 9 points, control units with 4 control pair points, status units with 16 points, and communication units with power supply. The RTU installation requirements are met by accumulating the necessary number of modern RTU modules to support the analog, control, status, and communication requirements for the site to be automated. Packaging of the minimum point count RTUs is available for the distribution line requirement. The substation automation requirement has the option of installing the traditional RTU in one cabinet with connections to the substation devices or distributing the RTU modules at the devices within the substation with fiber optic communications between the modules. The distributed RTU modules are connected to a data concentrating unit which in turn communicates with the host SCADA computer system.

The modern RTU accepts direct AC inputs from a variety of measurement devices including line-post sensors, current transformers, potential transformers, station service transformers, and transducers. Direct AC inputs with the processing capability in the modern RTU support fault current detection and harmonic content measurements. The modern RTU has the capability to report the magnitude, direction, and duration of fault current with time tagging of the fault event to 1-ms resolution. Monitoring and reporting of harmonic content in the distribution electric circuit are capabilities that are included in the modern RTU. The digital signal processing capability of the modern RTU supports the necessary calculations to report %THD for each voltage and current measurement at the automated distribution line or substation site.

The modern RTU includes logic capability to support the creation of algorithms to meet specific operating needs. Automatic transfer schemes have been built using automated switches and modern RTUs with the logic capability. This capability provides another option to the distribution line engineer when developing the method of service and addressing critical load concerns. The logic capability in the modern RTU has been used to create the algorithm to control distribution line switched capacitors for operation on a per-phase basis. The capacitors are switched on at zero voltage crossing and switched off at zero current crossing. The algorithm can be designed to switch the capacitors for various system parameters such as voltage, reactive load, time, etc. The remote control capability of the modern RTU then allows the system operator to take control of the capacitors to meet system reactive load needs.

The modern RTU has become a dynamic device with increased capabilities. The new logic and input capabilities are being exploited to expand the uses and applications of the modern RTU.

22.3.2 PLCs and IEDs

Programmable logic controllers (PLCs) and intelligent electronic devices (IEDs) are components of the distribution automation system, which meet specific operating and data gathering requirements. While there is some overlap in capability with the modern RTU, the authors are familiar with the use of PLCs for automatic isolation of the faulted power transformer in a two-bank substation and automatic transfer of load to the unfaulted power transformer to maintain an increased degree of reliability. The PLC communicates with the modern RTU in the substation to facilitate the remote operation of the substation facility. The typical PLC can support serial communications to a SCADA server. The modern RTU has the capability to communicate via an RS-232 interface with the PLC.

IEDs include electronic meters, electronic relays, and controls on specific substation equipment such as breakers, regulators, LTC on power transformers, etc. The IEDs also have the capability to support serial communications to a SCADA server. The authors' experience indicates that substation IEDs are either connected to a substation automation master via a substation LAN or reporting to the modern RTU (and thus to the SCADA host) via a serial interface using ASCII or vendor-specific protocol. Recent improvement in measurement accuracy and inclusion of power quality (harmonic content) especially in the realm of electronic relays are making the IED an important part of the substation protection and automation strategy.

22.3.3 Substation

The installation of the SCADA technology in the DA substation provides for the full automation of the distribution substation functions and features. The modular RTU supports the various substation sizes and configuration. The load on the power transformer is monitored and reported on a per-phase basis. The substation low-side bus voltage is monitored on a per-phase basis. The distribution feeder breaker is fully automated. Control of all breaker control points is provided including the ability to remotely set up the distribution feeder breaker to support energized distribution line work. The switched capacitor banks and substation regulation are controlled from the typical modular RTU installation. The load on the distribution feeder breaker is monitored and reported on a per-phase basis as well as on a three-phase basis. This capability is used to support the normal operations of the electric distribution system and to respond to system disturbances. The installation of the SCADA technology in the DA substation eliminates the need to dispatch personnel to the substation except for periodic maintenance and equipment failure.

22.3.4 Line

The DA distribution line applications include line monitoring, pole-mounted reclosers, gang-operated switches equipped with motor operators, switched capacitor banks, pole-mounted regulators, and pad-mounted automatic transfer switchgear. The modular RTU facilitates the automation of the distribution line applications. The use of the line post sensor facilitates the monitoring capability on a per-phase basis. The direct AC input from the sensors to the RTU supports monitoring of the normal load, voltage, and power factor measurements, and also the detection of fault current. The multifeatured distribution line DA device can be used effectively to identify the faulted sections of the distribution circuit during system disturbances, isolate the faulted sections, and restore service to the unfaulted sections of the distribution circuit. The direct AC inputs to the RTU also support the detection and reporting of harmonics and the %THD per phase for voltage and current. Fault detection (forward and reverse) per phase as well as fault detection on the residual current is supported in the RTU.

22.3.5 Tactical and Strategic Implementation Issues

As the threat of deregulation and competition emerges, retention of industrial and large commercial customers will become the priority for the electric utility. Every advantage will be sought by the electric utility to differentiate itself from other utilities. Reliable service, customer satisfaction, fast storm restorations, and power quality will be the goals of the utility. Differing strategies will be employed based on the customer in question and the particular mix of goals that the utility perceives will bring customer loyalty.

For large industrial and commercial customers, where the reliability of the electric service is important and outages of more than a few seconds can mean lost production runs or lost revenue, tactical automation solutions may be required. Tactical solutions are typically transfer schemes or switching schemes that can respond independently of operator action, reporting the actions that were initiated in response to loss of preferred service and/or line faults. The requirement to transfer source power, or

reconfigure a section of the electric distribution system to isolate and reconnect in a matter of seconds is the primary criteria. Tactical automation based on local processing provides the solution.

In cases where there are particularly sensitive customer requirements, tactical solutions are appropriate. When the same requirements are applied to a large area and/or customer base, a strategic solution based on a distribution management platform is preferred. This solution requires a DMS with a system operational model that reflects the current configuration of the electric distribution system. Automatic fault isolation and restoration applications, which can reconfigure the electric distribution system, require a “whole and dynamic system” model in order to operate correctly and efficiently.

22.3.6 Distribution Management Platform

So, while tactical automation requirements exist and have significant impact and high profile, goals that target system issues require a strategic solution. A DMS is the capstone for automation of the distribution system and includes advance distribution applications, integrated SCADA, integrated trouble call and outage management, and distribution operations training simulator (DOTS) at a minimum.

22.3.7 Advanced Distribution Applications

Transmission EMS systems have had advanced applications for many years. The distribution management platform will include advanced applications for distribution operations. A true DMS should include advanced applications such as volt/VAR control, automatic fault isolation and service restoration, operational power flows, contingency analysis, loss minimization, switching management, etc.

22.4 Integrated SCADA System

A functional DMS platform should be fully integrated with the distribution SCADA system. The SCADA–DMS interface should be fully implemented with the capability of passing data [discrete indication (status) and values (analog)] bi-directionally. The SCADA interface should also support device control. Figure 22.2 details the components of a DMS.

22.4.1 Trouble Call and Outage Management System

In addition to the base SCADA functionality and high-level DMS applications, the complete distribution automation system will include a trouble call and outage management system (TCOMS). TCOMS

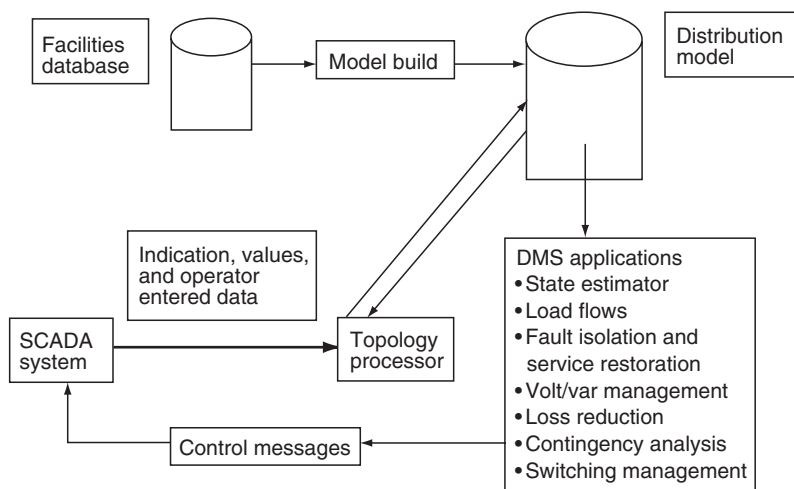


FIGURE 22.2 A DMS platform with SCADA interface.

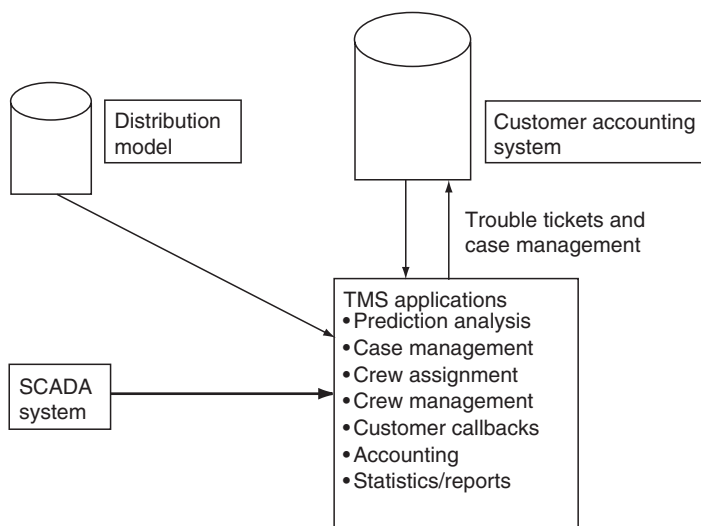


FIGURE 22.3 A TCOMS platform with SCADA interface.

collect trouble calls received by human operators and interactive voice recorders (IVR). The trouble calls are fed to an analysis/prediction engine that has a model of the distribution system with customer to electrical address relationships. Outage prediction is presented on a full graphics display that overlays the distribution system on CAD base information. A TMS also provides for the dispatch and management of crews, customer callbacks, accounting, and reports. A SCADA interface to a TCOMS provides the means to provide confirmed (SCADA telemetry) outage information to the prediction engine. Figure 22.3 shows a typical TCOMS.

22.4.2 Distribution Operations Training Simulator

With the graying of the American workforce and subsequent loss of expertise there is a requirement to provide better training for the distribution operator. A DOTS will provide the ability to train and test the distribution operator with real world scenarios captured (and replayed) through the DOTS. The DOTS instructor will be able to “tweak” the scenarios, varying complexity and speed of the simulation providing the distribution operator with the opportunity to learn best practices and to test his skills in an operational simulation without consequences of making operational mistakes on the “real distribution system.”

22.5 Security

In today’s environment, security of control systems has become an important topic. The dependence by electric utilities on digital control systems for operations coupled with the threat of terrorist activity whether by governments or individuals is beyond the scope of this article. However, it should be noted that most distribution SCADA systems (unlike transmission SCADA and EMS systems which are often on their own separate network) often reside on the utilities corporate networks elevating the risk of exposure to viruses, worms, and Trojan horses.

Every electric utility, no matter what size, should have the appropriate policy and procedures in place to secure their distribution “control system” from malicious or accidental harm. Securing administrator accounts, password aging policies, passwords with requirements on length and requirements on the mixture of character types, two factor authentication, virus protection, firewalls, intrusion detection, and securing the physical and electronic perimeter have all become a part of the vocabulary for SCADA system support staffs.

22.6 Practical Considerations

22.6.1 Choosing the Vendor

22.6.1.1 Choosing a Platform Vendor

In choosing a platform (SCADA, DMS, TCOMS) vendor there are several characteristics that should be kept in mind (these should be considered as a rule of thumb based on experience of what works and what does not). Choosing the right vendor is as important as choosing the right software package.

Vendor characteristics that the authors consider important are:

- A strong “product” philosophy. Having a strong product philosophy is typically a chicken and egg proposition. Which came first, the product or the philosophy? Having a baseline SCADA application can be a sign of maturity and stability. Did the platform vendor get there by design or did they back into it? Evidence of a product philosophy includes a baseline system that is in production and enhancements that are integrated in a planned manner with thorough testing on the enhancement and regression testing on the product along with complete and comprehensive documentation.
- A documented development and release path projected three to five years into the future.
- By inference from the first two bullets, a vendor who funds planned product enhancements from internal funds.
- A strong and active user group that is representative of the industry and industry drivers.
- A platform vendor that actively encourages its user group by incentive (e.g., dedicating part of its enhancement funding to user group initiatives).
- A vendor that is generally conservative in moving its platform to a new technology; one that does not overextend its own resources.
- Other considerations.
- As much as possible, purchase the platform as an off-the-shelf product (i.e., resist the urge to ask for customs that drive your system away from the vendor’s baseline).
- If possible, maintain/develop your own support staff.

All “customization” should be built around the inherent capabilities and flexibility of the system (i.e., do not generate excessive amounts of new code). Remember, you will have to reapply any code that you may have developed to every new release; or worse, you will have to pay the vendor to do it for you.

22.7 Standards

22.7.1 Internal Standards

The authors highly recommend the use of standards (internal to your organization) as a basis for ensuring a successful distribution automation or SCADA program. Well-documented construction standards that specify installation of RTUs, switches, and line sensors with mechanical and electrical specifications will ensure consistent equipment installations from site to site. Standards that cover nontrivial, but often overlooked issues can often spell the difference between acceptance and rejection by operational users and provide the additional benefit of having a system that is “maintainable” over the 10–20 years (or more) life of a system. Standards that fall in this category include standards that cover point-naming conventions, symbol standards, display standards, and the all-important operations manual.

22.7.2 Industry Standards

In general, standards fall into two categories: standards that are developed by organizations and commissions (e.g., EPRI, IEEE, ANSI, CCITT, ISO, etc.) and de facto standards that become standards

by virtue of widespread acceptance. As an example of what can occur, the reader is invited to consider what has happened in network protocols over the recent past with regard to the OSI model and TCP/IP.

Past history of SCADA and automation has been dominated by the proprietary nature of the various system vendor offerings. Database schemas and RTU communication protocols are exemplary of proprietary design philosophies utilized by SCADA platform and RTU vendors. Electric utilities that operate as part of the interconnected power grid have been frustrated by the lack of ability to share power system data between dissimilar energy management systems. The same frustration exists at the device level; RTU vendors, PLC vendors, electronic relay vendors, and meter vendors each having their own product protocols have created a “tower of babel” problem for utilities. Recently several communications standards organizations and vendor consortiums have proposed standards to address these deficiencies in intersystem data exchange, intrasystem data exchange (corporate data exchange), and device level interconnectivity. Some of the more notable examples of network protocol communication standards are ICCP (intercontrol center protocol), UCA (utility communication architecture), CCAPI (control center applications interface), and UIB (utility integration bus). For database schemas, EPRI’s CIM (common information model) is gaining supporters. In RTU, PLC, and IED communications, DNP 3.0 has also received much attention from the industry’s press.

In light of the number of standards that have appeared (and then disappeared) and the number of possibly competing “standards” that are available today, the authors, while acknowledging the value of standards, prefer to take (and recommend) a cautious approach to standards. A wait-and-see posture may be an effective strategy. Standards by definition must have proven themselves over time. Difficulties in immediately embracing new standards are due in part to vendors having been allowed to implement only portions of a standard, thereby nullifying the hopefully “plug-and-play” aspect for adding new devices. Also, the trend in communication protocols has been to add functionality in an attempt to be all-inclusive, which has resulted in an increased requirement on bandwidth. Practically speaking, utilities that have already existing infrastructure may find it economical to resist the deployment of new protocols. In the final analysis, as in any business decision, a “standard” should be accepted only if it adds value and benefit that exceeds the cost of implementation and deployment.

22.8 Deployment Considerations

The definition of the automation technology to be deployed should be clearly delineated. This definition includes the specification of the host systems, the communication infrastructure, the automated end-use devices, and the support infrastructure. This effort begins with the development of a detailed installation plan that takes into consideration the available resources. The pilot installation will never be any more than a pilot project until funding and manpower resources are identified and dedicated to the enterprise of implementing the technologies required to automate the electric distribution system. The implementation effort is best managed on an annual basis with stated incremental goals and objectives for the installation of automated devices. With the annual goals and objectives identified, then the budget process begins to ensure that adequate funding is available to support the implementation plan. To ensure adequate time to complete the initial project tasks, the planning should begin 18 to 24 months prior to the budget year. During this period, the identification of specific automation projects is completed. The initial design work is commenced with the specification of field automation equipment (e.g., substation RTU based on specific point count requirements and distribution line RTU). The verification of the communication to the selected automation site is an urgent early consideration in order to minimize the cost of achieving effective remote communications. As the installation year approaches, the associated automation equipment (e.g., switches, motor operators, sensors, etc.) must be verified to ensure that adequate supplies are stocked to support the implementation plan.

The creation of a SCADA database and display is on the critical path for new automated sites. The database and display are critical to the efficient completion of the installation and checkout tasks. Data must be provided to the database and display team with sufficient lead time to create the database and display for the automated site. The database and display are subsequently used to check out the

completed automated field device. The point assignment (PA) sheet is a project activity that merits serious attention. The PA sheet is the basis for the creation of the site-specific database in the SCADA system. The PA sheet should be created in a consistent and standard fashion. The importance of an accurate database and display cannot be overemphasized. The database and display form the basis for the remote operational decisions for the electric distribution system using the SCADA capability. Careful coordination of these project tasks is essential to the successful completion of the annual automation plans.

Training is another important consideration during the deployment of the automation technology. The training topics are as varied as the multidisciplined nature of the distribution automation project. Initial training requirements include the system support personnel in the use and deployment of the automation platform, the end user (operator) training, and installation teams. Many utilities now install new distribution facilities using energized line construction techniques. The automated field device adds a degree of complexity to the construction techniques to ensure adherence to safe practices and construction standards. These training issues should be addressed at the outset of the planning effort to ensure a successful distribution automation project.

22.8.1 Support Organization

The support organization must be as multidisciplined as the distribution automation system is multi-featured. The support to maintain a deployed distribution automation system should not be underestimated. Functional teams should be formed to address each discipline represented within the distribution automation system. The authors recommend forming a core team that is made up of representation from each area of discipline or area of responsibility within the distribution automation project. These areas of discipline include the following:

- Host SCADA system
- User interface
- Communication infrastructure
- Facilities design personnel for automated distribution substation and distribution line devices
- System software and interface developments
- Installation teams for automated distribution substation and distribution line devices
- End users (i.e., the operating personnel)

The remaining requirement for the core team is project leadership with responsibility for the project budget, scheduling, management reports, and overall direction of the distribution automation project. The interaction of the various disciplines within the distribution automation team will ensure that all project decisions are supporting the overall project goals. The close coordination of the various project teams through the core team is essential to minimizing decision conflict and maximizing the synergy of project decisions. The involvement of the end user at the very outset of the distribution automation project planning cannot be overemphasized. The operating personnel are the primary users of the distribution automation technology. The participation of the end user in all project decisions is essential to ensure that the distribution automation product meets business needs and improves the operating environment in the operating centers. One measure of good project decisions is found in the response of the end user. When the end user says, "I like it," then the project decision is clearly targeting the end user's business requirements. With this goal achieved, the distribution automation system is then in a position to begin meeting other corporate business needs for real-time data from the electric distribution system.